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Title: "Method and flow meter for measuring the composition and flow rate of fluids"

The present invention relates to a method and flow meter for measuring the composition and flow rates of individual components of a multiphase fluid.

The problem of how to meter oil-water-gas mixtures has been of interest to the petroleum industry since the early 1980s. Since then considerable research has been conducted into the development of a three-phase flow meter suitable for use in an industrial environment, for instance as described by R. Thorn, G.A. Johansen and E.A Hammer – 1997, "Recent developments in three-phase flow measurement", Meas. Sci. Technol., Vol.8, No. 7, pp. 691-701.

There are several techniques and known instruments for measuring multiphase flow, as will be further described below. Such instruments need to be reasonably accurate (typically ± 5 % of rate for each phase), non-intrusive, reliable, flow regime independent, and suitable for use over the full component fraction range. In spite of the large number of solutions that have been proposed in recent years, no commercially available three phase flow meter yet meets all these requirements.

The output of an oil/gas reservoir may vary greatly, depending on the location and age of the well. In addition to the oil and gas components, water, sand and wax may also be present in the produced well stream. Since the location and output of a well may vary so widely, the systems that have been designed to collect and process this output also vary considerably. The initial target of the oil

industry to develop a universal multiphase flow meter to replace the traditional separation/single phase metering solution currently used the fiscal monitoring of a well's output have yet to be realised.

Multiphase flow meters are increasingly used for well testing and allocation measurement. In order to optimise the production and life of an oil/gas field, operators need to be able to regularly monitor the output of each well in the field. The conventional way of doing this is to use a test separator. Test separators are expensive, occupy valuable space on a production platform and require a long time to monitor each well because of the stabilised flow conditions required. In addition test separators are only moderately accurate (typically ± 5 to 10 % of each phase flow rate) and cannot be used for continuous well monitoring. A three-phase flow meter could be used in the first instance instead of a test separator and in the long term as a permanent installation on each well. Such an arrangement would save the loss in production normally associated with well testing. Such loss is estimated to be approximately 2% for a typical offshore installation. Allocation metering is needed when a common pipeline is used to transport the output from a number of wells owned by different companies to a processing facility. This is currently achieved by passing the output of each well through a test separator before entering the common pipeline. However, in addition to the disadvantages of the test separator described above, dedicated test pipelines to each well are also required. A permanently installed three-phase flow meter would offer significant advantages for allocation metering.

According to a group of major oil companies the accuracy requirements for a multiphase meter within a gas volume fraction range of 0-99% and water cut range of 0-90%, is 5-10% relative error on the liquid and gas flow rate and water cut measurement error within 2% abs. More accurate measurements were required for production allocation applications. Commercial three-phase flow meters are now generally capable of measuring individual phase fraction's flow rate to an uncertainty of less than 10% over a reasonably wide range of flow rates and phase fractions. There are two areas of operation which need further investigation if flow rate uncertainty is to be reduced still further using current combinational measurement techniques; flow regime dependency and individual phase velocity measurement.

The present innovation provides a method and means which significantly reduce this uncertainty, in particularly the uncertainty related to flow regime dependency.

Se søkn 1998-4827 (NO 307393)

Some examples of commercially available non intrusive multiphase meters such as NO 304333, NO 304332, US 5,103,181, WO 00/45133 and US 6,097,786, measure the cross sectional composition and velocity of the phases to obtain flow rates. In order to provide accurate measurements, a homogeneous mixture in the cross section of the pipe is required. Effects due to inhomogenity in the longitudinal direction of the pipe is normally minimised by fast sampling of the cross-sectional composition. Multiphase meters are normally not mounted in a horizontal position due to the presence of laminar flow,

where water is in the bottom of the pipe and gas at the top, which would distort the measurement. Consequently, to achieve homogeneous mixture in the cross section of the pipe of a multiphase meter, it is common to install the multiphase meters in such a way that the flow is flowing in an upward or downward direction. Laminar flow may then be avoided. However, when a multiphase mixture containing gas and liquid are flowing in a vertical direction, annular flow can occur. Annular flow means that most of the liquid is distributed as a ring along the walls of the pipe and most of the gas is concentrated in the middle of the pipe. Annular flow distorts the measurement in a similar manner as laminar flow in a horizontal installation. In horizontal pipes pure annular flow where all the gas is in the middle of the pipe would normally only occur at higher gas fraction. However when the flow is flowing in vertical pipes, severe concentration of gas in the middle of the pipe has been experienced even at medium flow rates (a few m/s) and gas fractions as low as 10%. Even a concentration of gas in the middle of the pipe at lower gas fraction would introduce severe measurement errors.

NO 304333, US 5,103,181, US 6,097,786 and US 5,135,684 uses a nuclear densitometer. When a nuclear densitometer is used to measure the density it is not possible to obtain full coverage of the cross section of the pipe. Hence, in order to obtain accurate measurements, it relys on a homogeneous mixture in the cross section. Typical commercial available nuclear detectors for density measurement, based on the Caesium 662 keV peak, has a circular area with a radius of 2" and lower. For dual energy systems (x-Ray and γ-Ray) as described in US 5,135,684 and US 6,097,786, the coverage area is normally even smaller due to the need of a composite window in the pipe in order to allow radiation from the low energy x-Ray radiation to go through the pipe. The cover area in a 2" pipe with a typical commercial available γ-Ray densitometer is shown in figure 19. 70-80 % coverage can normally be achieved by proper arrangement of the detector and source. However, when used in a 6" pipe, it is challenging to achieve more than 30% coverage of the pipe cross section as shown in figure 20. One way to increase the coverage is to place the density measurement inside a venturi passage as in US 5,135,684 , however, if the diameter of the venturi passage is small compared to the diameter of the pipe, large pressure drops will occur limiting the operation envelope of the multiphase meter. Placing the nuclear density measurement inside a venturi passage also increases the amount of annular flow in the measurement section. When the source and detector is placed in the middle of the pipe, a too low density will be measured at annular flow. The error in the measurement will increase as the area of the pipe is increased. One way to compensate for this effect is to place the densitometer off centre. However, then the density would be measured too high if annular flow is present at low gas fractions.

Yet another way to minimise the effect of annular flow is to use a mixing device. US Re. 36,597 describes a method where a positive displacement meter is used to both measure the total flow rate and homogenise the multiphase mixture in advance of the composition measurement. Annular flow is then minimised, however, the multiphase meter becomes highly intrusive and fragile since it depends on a mechanical

restricting or rotating device located in the multiphase stream. The repeatability of the measurement over time would also be vulnerable to sand erosion. Another way to reduce the presence of annular flow is to use a mixer. US 5,135,684 refers to a method where a hold up tank is used to homogenise the multiphase flow. However, the structure is highly intrusive creating pressure drop and hence limiting the production capabilities from the wells. The performance of the mixer would also be dependent of the flow rate and pattern such as length of gas and liquid slugs and could therefore limit the operational envelope of such a multiphase meter. Another method based on mixing of the multiphase flow is described in US 6,272,934.

Yet another way to reduce the effect of annular flow is to perform the composition measurement at the cross section of an inverted venturi is shown in WO00/45133, figure 1. However this method is also intrusive and the repeatability of the measurement over time would also be vulnerable to sand erosion.

Also known are multiphase composition and flow meters based on microwaves.
US 4,458,524 (1984) discloses a multiphase flow meter that measures the permittivity (dielectric constant), density, temperature and pressure. Such device uses phase shift between two receiving antennas to determine the permittivity.

Other techniques are further known being based on resonance frequency measurement. Examples of such techniques are disclosed in W03/034051 and US 6,466,035. Techniques based on resonance frequency measurements are normally limited to multiphase conditions where the loss inside the pipe is small and would therefore normally not work for high water cut applications and saline water due to the high dielectric loss of the mixture. US 5,103,181 describes a method based on measurement of constructive and destructive interference patterns in the pipe.

However, none of the above mentioned techniques are both non intrusive and able to detect and compensate the measurements for the degree of gas concentration in the middle of the pipe (annular flow). The present invention relates to a non intrusive method to detect the presence of annular flow, compensate the measurement as a function of the degree of annular flow in order to obtain accurate flow-rate measurements of the individual components of a multiphase mixture.

It is the purpose of this invention to provide a method for identifying gas concentration in the middle of the pipe and to further compensate permittivity and density measurements for the measurement error related to the degree of gas concentration in the middle of the pipe
It is further the purpose of this invention to provide an improved apparatus to avoid the above mentioned limitations of the performance of presently known techniques for multiphase flow measurements.

It is still further the purpose of this invention to provide a single low-cost structure for performing accurate measurement of oil, water and gas flow rates.

And, it is the purpose of this invention to provide a non intrusive structure for performing the measurements without the need for an upstream mixing device.

The method according to the present invention is characterized in that,

a. electrical loss and phase measurements are performed in at least two directions of the pipe,
b. the degree of annular flow (concentration of gas in the middle of the pipe) is detected based on the above measurements,
c. the permittivity of the flow mixture is calculated based on the results from features a and b above, and corrected for the degree of annular flow (gas concentration in the middle of the pipe),
d. the mixture density is measured and compensated by the degree of annular flow,
e. the velocity of liquid and gas are measured
f. the temperature and pressure are measured

based on the knowledge of densities and permittivities of the fluids and the result from the above features a-f; the oil, water and gas mass flow and volume flow rates of the fluid are calculated as defined in the independent claim 1.

The flow meter according to the invention is further characterized by the features as defined in the independent claim 14.

Dependent claims 2 – 13 and 15 - 26 define preferred embodiments of the invention.

The invention will be further described in the following with reference to the figures, where:

Fig. 1 shows a graphical representation of three examples of annular flow in a 4" pipe,

Fig. 2 shows a simple sketch of the invention,

Fig. 3 shows a phase vs. frequency curve,

Fig. 4 shows graph showing the raw measurement, and

Fig. 5 shows the corresponding compensated measurement, both using neural networks,

Fig. 6 shows an electric field below cut-off frequency of pipe or at high loss,

Fig. 7 illustrates an electric field in sensor at low loss above cut-off frequency,

Fig. 8 shows Phase response at low loss,

Fig. 9 illustrates a simple sketch of a sensor probe arrangement,

Fig. 10 is a sketch of probe layout,

Fig. 11 represents a sketch of an arrangement with gamma ray density measurement,

Fig. 12 illustrates an venturi density measurement arrangement,

Fig. 13 shows a diagram disclosing measured frequencies of cross sectional probes,

Fig. 14 shows a diagram disclosing measured frequency of longitudinal probes,

Fig. 15 shows a diagram with compensated (using neural networks) vs. theoretical measurements,

Fig. 16 illustrates a simple sketch of a gamma ray absorption density measurement in a typical 2" pipe, and

Fig. 17 depicts a simple sketch of a gamma ray absorption density measurement in a typical 6" pipe

The multiphase meter according to the invention includes three main elements as follows:

1) Measurements to detect concentration of gas in the middle of the pipe (annular flow). In vertical pipes the gas is frequently concentrated in the middle of the pipe and the liquid is concentrated along the pipe wall. In extreme cases, all the gas can be flowing in the middle of the pipe. In order to identify gas concentration in the middle of the pipe, the frequency and loss between one transmitting antenna and two receiving antennas at two different positions is measured at three or more pre determined phase differences between the two receiving antennas. The transmitting antenna and the two receiving antennas are located in at least two cross sections of the pipe. The loss and phase measurements are done over a wide frequency band (typical 10 Mhz to 3,5 Ghz). By using neural networks it is possible to recognise the characteristically response of annular flow (gas concentration in the middle of the pipe).
2) Measurements of fractional distribution of oil, water and gas in cross section of the pipe. The fractional distribution of oil, water and gas in the cross section is based on measurement of the permittivity and density and known values of permittivity and density of oil, water and gas. By measuring the temperature and pressure, the measurement can be compensated for variations in temperature and pressure. The measured permittivity and density are compensated for the degree of gas concentration by a neural network model which calculates the corresponding well mixed density and permittivity ("well mixed density and permittivity" in this context means the theoretical density and permittivity that would be measured in an equivalent homogeneous multiphase mixture).
3) Measurements of liquid and gas velocity. The velocities are measured by sampling small variations in the multiphase mixture at two cross-sections of the pipe separated by a known distance and then cross-correlating the sampled measurement. By analysing the cross-correlated signal and identify the two largest point in combination to statistically sorting of the measurement, it is possible to obtain a measurement of the oil and gas velocity.

By combining the measurements from points 2) and 3) above and knowing the cross-sectional area of the pipe (sensor) and the density of oil, water and gas - it is possible to calculate the oil, water and gas volumetric and mass based flow rates.

Disadvantages with the existing solutions.
The weakness of existing multiphase meters is mainly related to two factors, namely that:

1) All existing multiphase meters rely on a homogenous mixture between oil water and gas in the cross section of the pipe. At annular flow (gas concentration in the middle of the pipe), great measurement errors will occur. In Fig. 1 is shown a graphical representation of three examples of annular flow in a 4" pipe and the effect on the measurement with a typical gamma densitometer based on a 2" detector. Although this is an extreme case since all the gas is concentrated in the middle of the pipe, it illustrates that great errors will occur in the measurements.

2) Need of using a mechanical mixing element. Some multiphase meters use a mechanical mixing device to homogenise the multiphase flow. A mixer would reduce the amount of annular flow, however it makes the meter highly intrusive. Some of the mixers may also contain moving mechanical objects that are vulnerable to sand erosion and could even be damaged by fast variations in the velocity associated with start up of a well.

Uniqueness of the present invention.
The uniqueness of the invention is the ability to detect presence of annular flow (gas concentration in the middle of the pipe) and compensate the measurement error related to the degree of annular flow. The attached Fig. 2 shows a simple sketch of the invention:

Loss and phase measurements are performed by measuring the received power and phase difference of a broad band signal (typical 10 Mhz – 3,5 Ghz) which is transmitted from a sending antenna (probe) and received at two receiving probes. The measurement is done at at least two and preferable three planes in the pipe where one plane is at the cross section, a second is at the longitudinal direction and a third at an angle (such as 45 degrees) to the flow direction. The frequency is varied form 10 Mhz until 3,5 Ghz depending on the pipe diameter. By recording the frequency at at least three pre determined phase differences and using a calibration constant for the system, the permittivity within the pipe can be measured.

By analysing the distribution of the phase measurements, annular flow can be detected and compensated for. The reason for this is that the phase vs. frequency curve is more or less linear at well mixed flow

however at annular flow, the curve is non-linear as shown in the attached Fig. 3 . This represents new and inventive features which are previously not described in the literature.
Since it is demanding to make accurate models for such a complex and nonlinear measurement, neural networks are trained to detect annular flow and compensate the measurement. Laboratory tests based on this method has provided 100% identification of annular flow. Neural Networks is also used to compensate the error in the measurement due to gas concentration in the middle of the pipe. Based on the measurement (measured frequency and frequency distribution in all the measurement planes), the well mixed "theoretical" measurement frequency can be calculated. Attached is a graph showing the raw measurement, Fig. 4, and the corresponding compensated measurement, Fig. 5, using neural networks

When the pipe acts as a wave guide (low loss), the method for detecting annular flow is slightly different. Below the cut-off frequency, the electric field will propagate according to plane wave theory as illustrated in the Fig. 6. At low loss in the pipe and above the cut-off frequency f_c, the electric field in the pipe is shown in Fig. 7, which correspond to TE_{11}. When the field in the pipe changes from plane wave propagation into TE_{11}, a step occurs in the phase difference of the receiving antennas. The phase step is illustrated in Fig. 8. By applying a frequency sweep on the transmitter and measuring the frequency at at least three pre determined phase differences, the frequency of the phase step, which is a measure of the cut-off frequency f_c of the pipe, can be measured.

The presence of annular flow at low loss is by selecting a measurement frequency that is well below the cut off frequency of the pipe. Since the cut of frequency is a function of the permittivity of the multiphase mixture inside the pipe, the measurement frequency will vary as a function of the permittivity. At the measurement frequency, the pipe would not act as a wave guide and consequently the energy field will be as shown in Fig. 6. The loss is measured by sending at the selected measurement frequency and measuring the received power at the two receiving probes. By comparing the measured loss in the three measurement planes, annular flow can be detected and compensated using neural networks as described above.

In order to calculate the oil, water and gas fractions in the cross section of the pipe, a measurement of the cross sectional density is also required. This measurement would also be affected by gas concentration in the middle of the pipe. Knowing the presence and degree of gas concentration in the pipe, the density measurement can be compensated for the effect of gas concentration in a similar manner using neural networks.

The density measurement is, according to the invention, performed in two ways depending on the application:

1) Gamma ray absorption. By measuring the gamma ray absorption of the multiphase mixture and knowing the absorption coefficient of oil water and gas and the permittivity of the multiphase mixture and the permittivity of oil water and gas it is possible to calculate the mixture density in an iterative calculation. As a part of this iteration, the gamma ray absorption measurement can be corrected for presence of annular flow by a neural network.
2) Venturi mass flow measurement. A venturi can be used to measure the density of the mixture. The pressure drop across the inlet of a venturi is a function of the mass flow and density of the multiphase mixture. Furthermore, the pressure drop across the outlet of the venturi is a function of the mass flow, density and compressibility of the multiphase mixture. Combining the pressure measurement of the inlet and outlet of the venturi together with the measurement of the gas and liquid velocity from cross correlation it is possible to calculate the mixture density in an iterative fashion. However, at gas concentration in the middle of the pipe, error will occur in the measurements. Then, as a part of the iteration, the measurement will be corrected for the degree of of annular flow (gas concentration) as a part of the iterations to calculate the mixture density.

A combination of Gamma ray absorption (pt 1) and Venturi (pt 2) may also be used. This combination will in some cases extend the operation envelope of the measurement system.

Fig. 9 illustrates a simple mechanical structure that can be used to measure the dielectric properties (permittivity), cross sectional flow regime (annular or well mixed) and velocity of a multiphase flow. The probes (antennas) are in effect coaxial conductors that are inserted into the pipe designed such that the centre conducting wire is isolated from the pipe wall by a dielectric material such as plastic or ceramic, as can be seen in Fig 11. Three of the probes are used as transmitters and three of the probes are used as receivers. The direction of the flow is illustrated by an arrow.

The sensor is used to measure the composition and velocity (liquid and gas) of the multiphase mixture.

Velocity Measurement

By continuously transmitting and measuring the response at the probe pair Tx1/Rx2 and Tx2/Rx3 located at a known distance S+L, one can create two time varying signals that are shifted in time equal to the time it takes the multiphase flow to travel between the two probe pairs. The measurement frequency is selected such that no energy is going in the longitudinal direction and at low loss the frequency would typical be substantially below and a function of the measured cut-off frequency of the pipe. By cross correlating the two signals using the formula:

Equation 1:

$$R_{xy}(\tau) = \lim_{T \to \infty} \frac{1}{T} \int_0^T x(t-\tau) * y(t)dt$$

where x(t) and y(t) are the sampled signals, the time delay τ can be calculated. The time delay τ between the signals x(t) and y(t) is a measure of the time it takes a disturbance in the flow to go from the first to the second set of probes. Using high frequency signals to measure the flow disturbances also enables use of high sampling rate. Hence the signal contains information about small variations such as small gas bubbles in the liquid phase or water droplets in the oil phase or oil droplets in the water phase that typical represents the velocity of the liquid, and large variations such as gas slugs that represent the velocity of the gas phase. By applying the appropriate filtering of the sampled data and statistically sorting of the cross correlated velocities, it is possible to obtain a measure of both the liquid and gas velocity (v_{liq} and v_{gas}).

Composition Measurement

However in order to measure the flowrates of oil, water and gas, it is required to measure the cross sectional composition (%oil, %water & %gas) of the multiphase mixture of oil, water and gas. By measuring the mixture permittivity ε_{mix} and mixture density ρ_{mix} the following equations can be used:

Equation 2 :

$$\Phi_{oil} + \Phi_{water} + \Phi_{gas} = 1$$

where :

Φ_{oil} = Cross sectional volume fraction of oil

Φ_{water} = Cross sectional volume fraction of water

Φ_{gas} = Cross sectional volume fraction of gas

Equation 3:

$$\Phi_{oil} \times \rho_{oil} + \Phi_{water} \times \rho_{water} + \Phi_{gas} \times \rho_{gas} = \rho_{mix}$$

where:

ρ_{oil} = Density of oil

ρ_{water} = Density of water

ρ_{gas} = Density of gas

ρ_{mix} = Measured density

A temperature and pressure measurement is also required in order to compensate the above density parameters for temperature and pressure variations but, for simplicity, these will be ignored for the following discussions of the measurement principle.

The Bruggeman mixing equation relates the permittivity (dielectric constant) of a two component mixture to the volume fractions of the components. If the two component mixture is droplets as an inner phase dispersed in a continuous media of an outer phase, the equation become:

Equation 4:

$$\frac{\varepsilon_{inner}-\varepsilon_{mix}}{\varepsilon_{inner}-\varepsilon_{outer}} * \left(\frac{\varepsilon_{outer}}{\varepsilon_{mix}}\right)^{\frac{1}{3}} = 1-\frac{\phi_{inner}}{\phi_{inner}+\varphi_{outer}}$$

where:

ε_{inner} = Permittivity of the inner phase (dispersed phase)
ε_{outer} = Permittivity of the outer phase (continuous phase)
ε_{mix} = Measured permittivity of the mixture
Φ_{inner} = Volume fraction of inner phase (dispersed phase)
Φ_{outer} = Volume fraction of outer phase (continuous phase)

A temperature and pressure measurement is also required in order to compensate the above permittivity parameters for temperature and pressure variations but, for simplicity, these will be ignored for the following discussions of the measurement principle.

The equation above can also be used for a three-phase mixture such as oil, water and gas in which the inner phase is a well mixed combination of two of the phases dispersed in an outer phase. E.g., an inner oil/water mixture may be dispersed in an outer continuous media of gas and similarly, gas bubbles may be dispersed in an outer continuous media of an oil/water mixture.

The lowest cut-off frequency of a circular wave guide is TE_{11} at:

Equation 5:

$$f_c = \frac{0.293}{r\sqrt{\mu\varepsilon}}$$

where:

f_c = Cut-off frequency

r	=	Radius of pipe
ε	=	Permittivity (dielectric constant) inside the wave guide (pipe)
μ	=	Permeability inside the wave guide (pipe)

Below the cut-off frequency, the electric field will propagate according to plane wave theory as illustrated in figure 6. At low loss in the pipe and above the cut-off frequency f_c, the electric field in the pipe is shown in fig 7 which correspond to TE_{11}. When the field in the pipe changes from plane wave propagation into TE_{11}, a step occurs in the phase difference of the receiving antennas Rx1 and Rx2 of Fig. 9. The phase step is illustrated in Fig. 8. By applying a frequency sweep on the transmitter Tx1 and measuring the frequency at at least three pre determined phase differences between the two receiving probes, the frequency location (measured frequency) of the step change in the phase difference between the receiving probes can be measured. Then, the measured frequency is a measure of the cut-off frequency f_c of the pipe.

Equation 5 can be rearranged as:

Equation 6:

$$\varepsilon = \frac{k_2^2}{f_c^2}$$

where:

$$k_2 = \frac{0.293}{r\sqrt{\mu}}$$

f_c	=	Frequency of electromagnetic wave (cut-off frequency of TE_{11})
ε	=	Permittivity (dielectric constant) inside the pipe

hence k_2 can be determined by measuring the frequency f_c with a known permittivity inside the pipe.

The permittivity of the mixture at high loss inside the pipe (sensor) is measured by applying a frequency sweep to one of the transmitting antennas and recording the frequency at at least three predetermined phase differences between two of the receiving antennas located at a distance S and distance L from the transmitting antenna. Below the cut off frequency or when the loss inside the pipe is large, the electric field will propagate according to plane wave theory. The phase difference between the two receiving antennas represents the wave travel time between the two points and can be written as:

Equation 7:

$$\Delta S = \lambda \frac{\Delta \theta}{2\pi}$$

where:

ΔS	=	L-S (ref. fig. 12)
$\Delta\theta$	=	Phase difference between receiving antennas
λ	=	Wavelength

According to plane wave theory, the velocity of an electromagnetic wave can be expressed as:

Equation 8:

$$v = \lambda f = \frac{c}{\sqrt{\mu\varepsilon}}$$

where:

f	=	Frequency of electromagnetic wave
λ	=	Wavelength of electromagnetic wave
ε	=	Permittivity (dielectric constant) inside the pipe
μ	=	Permeability inside the pipe
c	=	Speed of light

Since the frequency is measured at predetermined phase difference, equation 6 and 7 can be combined giving:

Equation 9:

$$\varepsilon = \frac{k_1^{\,2}}{f^2}$$

where:

$$k_1 = \frac{c\Delta\theta}{\Delta S\sqrt{\mu}}$$

f	=	Frequency of electromagnetic wave
ε	=	Permittivity (dielectric constant) inside the pipe

k_1 can be determined by measuring the frequency at the phase difference $\Delta\theta$ with a known permittivity inside the pipe.

The permittivity within the pipe is measured in at least two directions. First, the transmitter is sending on Tx1 and receiving on Rx2 and Rx1 (figure 9) performing a measurement of the permittivity in the cross section of the pipe. Then the transmitter is sending on Tx3 and measuring on Rx2 and Rx3 performing a measurement of the permittivity in the longitudinal direction of the pipe. It is also possible to perform measurements of the permittivity by sending on Tx3 and receiving on Rx1 and Rx2 and hence performing a measurement that lies between the cross section and longitudinal measurement.

The effect of annular flow on the measured phase response of cross sectional probe may be explained as follows. When the flow is well mixed the phase-difference vs. frequency would be almost linear. If the flow is annular, which distort the symmetry of the L and S path from the transmitter to the receivers, the phase difference would be much more curved. The longitudinal probes, as shown in Fig. 14, are less affected by annular flow since the symmetry is maintained also at annular flow.

By measuring the frequency at several predetermined phase differences, it is possible to both detect and compensate for the effect on the measurements. Experimental data has shown that the effect on the measurement is related to the slope ($d\theta/df$) of the phase difference. One way to compensate for the error introduced by annular flow is to first train a neural network to recognise the presence of annular flow. Then a second neural network could be trained to compensate for the error in the measurements as shown in Fig. 15. Fig. 13 and 14 illustrates a typical response from the probes in the presence of annular flow. From Fig. 14 it can be seen that the frequency at the predetermined phase difference shifts to a higher value when the amount [% of total volume] of annular flow increases and that the response behave predictable over the entire conductivity range. The cross-sectional probes behave quite different as represented by Fig. 13. For small amount of annular flow, the response is similar as the longitudinal probes, however as the amount of annular flow increases, the both the slope of the curve and frequency of the phase points is very different from the longitudinal probes.

The presence of annular flow can also be measured by measuring the loss in the longitudinal and cross-sectional direction. First, the transmitter is sending on Tx1 and receiving on Rx2 and Rx1 performing a measurement of the relative loss in the cross section of the pipe. Then the transmitter is sending on Tx3 and measuring on Rx2 and Rx3 performing a measurement the relative loss in the longitudinal direction of the pipe. It is also possible to perform measurements of the permittivity by sending on Tx3 and receiving on Rx1 and Rx2 and hence performing a measurement that lies between the cross section and longitudinal measurement. At annular flow (gas concentration in the middle of the pipe), the longitudinal measurement would be different compared to the cross-sectional measurement. The measurement has to be made in such a way that the pipe does not act as a wave guide. One way to achieve this is by selecting a measurement frequency that is below the measured cut-off frequency for TE_{11}.

Measurement of gamma ray absorption is a widely used technique for density measurement. This technique takes into account that absorption of photon beam radiation in any material in the pipe can be expressed by the formula:

Equation 10:

$$N = N_0 e^{-\mu\rho d}$$

where:

N_0	=	Empty pipe count rate (radiation)
N	=	Measured count rate (radiation)
μ	=	Radiation mass absorption coefficient of the material inside the pipe.
d	=	Transmission length of the radiation through the cross-section of the pipe
ρ	=	Density of the material inside the pipe

By measuring the count rate with a media inside the pipe with a known absorption coefficient such as fresh water, the parameter d can be determined according to equation 11:

Equation 11:

$$d = -\frac{\ln\left(\frac{N_{fresh-water}}{N_0}\right)}{\rho_{fresh-water} * \mu_{fresh-water}}$$

where :

N_0	=	Empty pipe count rate (radiation)
$N_{fresh\text{-}water}$	=	Measured count rate (radiation) in fresh water
$\mu_{fresh\text{-}water}$	=	Radiation mass absorption coefficient of fresh water
d	=	Transmission length of the radiation through the cross-section of the pipe
$\rho_{fresh\text{-}water}$	=	Density of fresh-water

Since the density measurement does not cover the whole cross sectional area of the pipe and hence rely on a homogeneous mixture in the cross section. The cover area in a 2" pipe with a typical commercial available γ-Ray densitometer is shown in Fig 16. 70-80 % coverage can normally be achieved by proper arrangement of the detector and source. However, when used in a 6" pipe, Fig. 17, it is challenging to

achieve more than 30% coverage of the pipe cross section. However knowing the degree of gas concentration in the middle of the pipe, it is possible to compensate the measurement to provide a more correct measurement of the cross sectional liquid and gas ratio. The compensation algorithm can either be derived from a geometrical description of the nuclear coverage area inside the pipe or by using a neural network trained to correct the measurements.

Yet another way to measure the density is to use a venture mass flow meter. Any restriction in the pipe will result in a change in the velocity of the multiphase mixture and introduce a pressure drop across the restriction. Based on the theory of fluid dynamics the square root of the pressure drop is proportional to the total mass flow rate in the pipe. A venturi tube is a structure where the pipe diameter is gradually reduced into a section of the pipe with a smaller diameter. Then the diameter is gradually expanded to its original size. Mass flow measurements with such a structure are described in ISO 5167-1.

According to Bernoulli's equation, the mass flow rate can be calculated as:

Equation 12 :

$$Qm = \frac{C}{\sqrt{\beta^2 - 1}} \varepsilon \frac{\pi}{4} D^2 \sqrt{\frac{2\Delta p}{\rho}}$$

where:

Qm	=	Total mass flow rate
C	=	Discharge coefficient
ε	=	Expansion coefficient
β	=	Diameter ratio between venturi throat and pipe
D	=	Diameter of pipe
Δp	=	Measured pressure drop between inlet an venture throat
ρ	=	Density of the multiphase mixture

The pressure recovery at the outlet of the venturi will be dependent on the mass flow rate, density and compressibility of the multiphase fluid. When the gas content of the multiphase mixture is high, the pressure recovery at the outlet of the venture will be greater compared to a multiphase mixture with low gas content. Hence, by combining equation 12 with a measurement of the pressure recovery at the outlet of the venturi, it is possible to obtain a more accurate measurement of the density of the multiphase mixture.

Equation 1-12 will together with the neural network based correction functions may be used in an iterative calculation to derive the oil, water and gas mass and volume flow rates.

CLAIMS

1. Method for measuring the composition and flow rate of fluid compromising a mixture of e.g. oil, water and gas in a pipe CHARACTERIZED IN that :
   a. electrical loss and phase measurements are performed in at least two directions of the pipe,
   b. the degree of annular flow (concentration of gas in the middle of the pipe) is detected based on the above measurements,
   c. the permittivity of the flow mixture is calculated based on the results from features a and b above, and corrected for the degree of annular flow (gas concentration in the middle of the pipe),
   d. the mixture density is measured and compensated by the degree of annular flow,
   e. the velocity of liquid and gas are measured
   f. the temperature and pressure are measured
   g. based on the knowledge of densities and permittivities of the fluids and the result from the above features a-f; the oil, water and gas mass flow and volume flow rates of the fluid are calculated.
2. Method according to claim 1,
   CHARACTERIZED IN that the electrical measurements are performed in the cross sectional and longitudinal direction of the pipe
3. Method according to claims 1 and 2,
   CHARACTERIZED IN that the electrical measurements are performed by doing a frequency sweep on a transmitting antenna (probe) and recording the frequency at at least three pre determined phase differences on two receiving antennas (probes).
4. Method according to claims 1 - 3,
   CHARACTERIZED IN that the electrical measurements are performed by transmitting at a frequency on the transmitting antenna (probe) that is selected as a function of the cut-off frequency of the pipe and recording the power on two receiving antennas (probes).
5. Method according to claims 1 - 3,
   CHARACTERIZED IN that the degree of annular flow is detected based on a measure of the shape of the phase response vs. frequency.
6. Method according to claim 5,
   CHARACTERIZED IN that the slope of the phase curve vs. frequency at some pre determined phase differences is used as a measure of the shape of the response.
7. Method according to claim 4,

CHARACTERIZED IN that the measured power difference on the received antennas are used to detect presence of annular flow.

8. Method according to claims 1 - 7,

   CHARACTERIZED IN that the density of the fluid mixture is measured utilising γ-ray absorption techniques.

9. Method according to claims 1 - 7,

   CHARACTERIZED IN that the mixture density is measured using a venturi.

10. Method according to claims 1 - 7,

    CHARACTERIZED IN that the mixture density is measured based on the pressure drop of the inlet and pressure recovery of the outlet of a venturi.

11. Method according to claims 1 - 7,

    CHARACTERIZED IN that the liquid and gas velocity is measured by cross correlating measurements performed at two sets of probes located at a known distance.

12. Method according to claim 11,

    CHARACTERIZED IN that the measurement frequency is selected as a function of the cut-off frequency of the pipe with the multiphase fluid mixture present in the pipe.

13. Method according to claims 1 - 7

    CHARACTERIZED in that the density of the fluid mixture is measured utilising γ-ray absorption techniques and based on the pressure drop of the inlet and pressure recovery of the outlet of a venturi.

14. Flow meter for measuring the composition and flow rate of a fluid compromising a mixture of e.g. oil, water and gas in a pipe,

    CHARACTERIZED in that

    a. electrical loss and phase measurements are performed in at least two directions of the pipe by means of an electrical measuring device,
    b. the degree of annular flow (concentration of gas in the middle of the pipe) is detected based on the above measurements by using a suitable data model,
    c. the permittivity of the flow mixture is calculated based on the results from features a and b above, and corrected for the degree of annular flow (gas concentration in the middle of the pipe), by means of a mathematical program,
    d. the mixture density is measured by a measuring device and compensated by the degree of annular flow,
    e. the velocity of liquid and gas are measured by means of a measuring device,
    f. the temperature and pressure are measured by means of a measuring device, and

g. based on the knowledge of densities and permittivities of the fluids and the result from the above features a-f; the oil, water and gas mass flow and volume flow rates of the fluid are calculated using a data program.

15. Method according to claim 1,
CHARACTERIZED IN that the electrical measurements are performed in the cross sectional and longitudinal direction of the pipe
16. Method according to claims 1 and 2,
CHARACTERIZED IN that the electrical measurements are performed by doing a frequency sweep on a transmitting antenna (probe) and recording the frequency at at least three pre determined phase differences on two receiving antennas (probes).
17. Method according to claims 1 - 3,
CHARACTERIZED IN that the electrical measurements are performed by transmitting at a frequency on the transmitting antenna (probe) that is selected as a function of the cut-off frequency of the pipe and recording the power on two receiving antennas (probes).
18. Method according to claims 1 - 3,
CHARACTERIZED IN that the degree of annular flow is detected based on a measure of the shape of the phase response vs. frequency.
19. Method according to claim 5,
CHARACTERIZED IN that the slope of the phase curve vs. frequency at some pre determined phase differences is used as a measure of the shape of the response.
20. Method according to claim 4,
CHARACTERIZED IN that the measured power difference on the received antennas are used to detect presence of annular flow.
21. Method according to claims 1 - 7,
CHARACTERIZED IN that the density of the fluid mixture is measured utilising γ-ray absorption techniques.
22. Method according to claims 1 - 7,
CHARACTERIZED IN that the mixture density is measured using a venturi.
23. Method according to claims 1 - 7,
CHARACTERIZED IN that the mixture density is measured based on the pressure drop of the inlet and pressure recovery of the outlet of a venturi.
24. Method according to claims 1 - 7,
CHARACTERIZED IN that the liquid and gas velocity is measured by cross correlating measurements performed at two sets of probes located at a known distance.

25. Method according to claim 11,

CHARACTERIZED IN that the measurement frequency is selected as a function of the cut-off frequency of the pipe with the multiphase fluid mixture present in the pipe.

26. Method according to claims 1 - 7

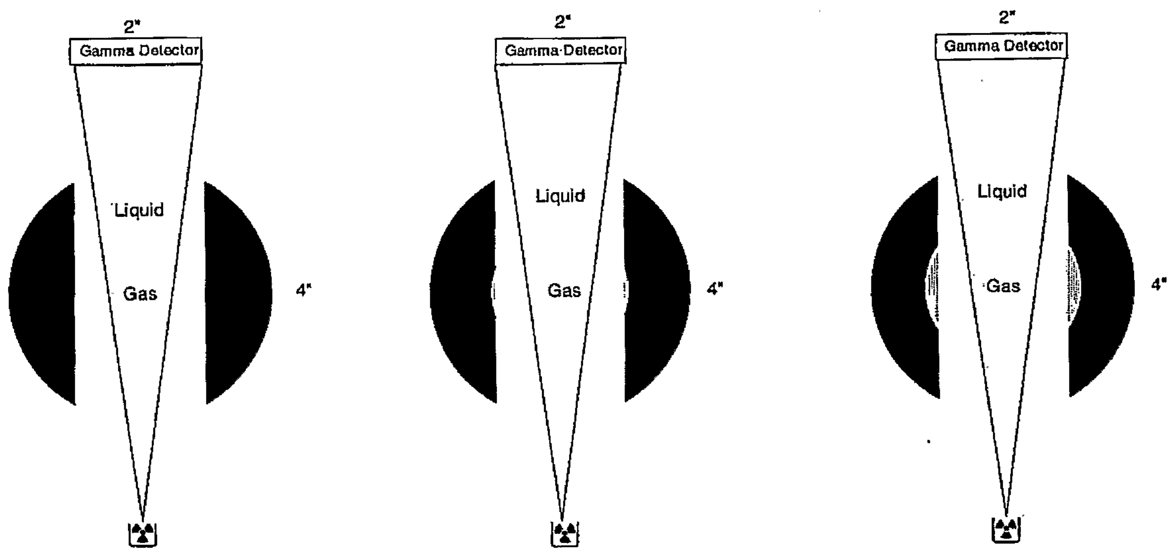
CHARACTERIZED in that the density of the fluid mixture is measured utilising γ-ray absorption techniques and based on the pressure drop of the inlet and pressure recovery of the outlet of a venturi.

Abstract

Method and flow meter for measuring the composition and flow rate of fluid compromising a mixture of e.g. oil, water and gas in a pipe. The method is based on the following features:

g. electrical loss and phase measurements is performed in at least two directions of the pipe
h. the presence of annular flow (concentration of gas in the middle of the pipe) is detected based on the above measurements
i. the permittivity of the mixture assuming well mixed flow is calculated based on the results from a and b and a correction function to compensate the permittivity related to the degree of annular flow (gas concentration in the middle of the pipe)
j. the mixture density is measured, and if annular flow is present, compensated by the degree of annular flow by a correction function
k. the velocity of liquid and gas is measured
l. the temperature and pressure is measured
m. from knowledge about oil, water and gas densities and permittivities and the result from pt. a-f; the oil, water and gas mass flow and volume flow rates are calculated

Fig. 1

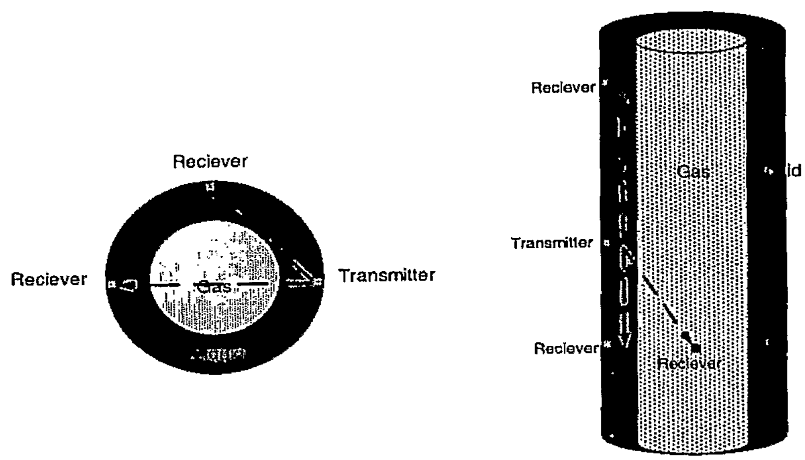


Actual GVF (%Gas) : 10.3%
Measured GVF : 25.0%

Actual GVF (%Gas) : 25.1%
Measured GVF : 49.5%

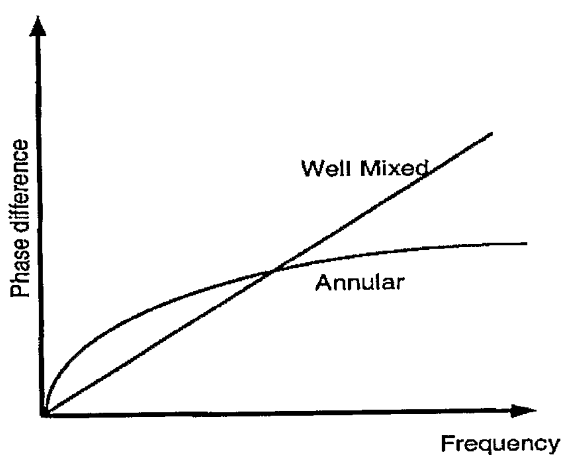
Actual GVF (%Gas) : 36.5%
Measured GVF : 55.1%

Fig. 2



Reciever
Reciever
Gas
Transmitter
Reciever
Gas
Transmitter
Reciever
Reciever

Fig. 3



Phase difference
Well Mixed
Annular
Frequency

Fig. 4

1 D Measurements

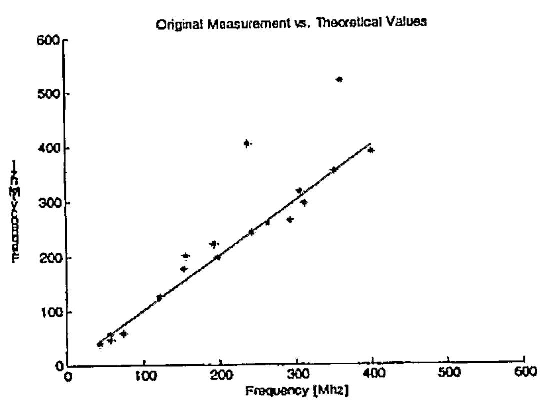


Fig. 5

3D Measurements

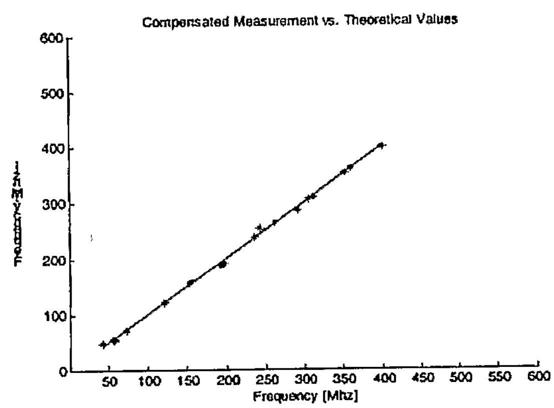


Fig. 6

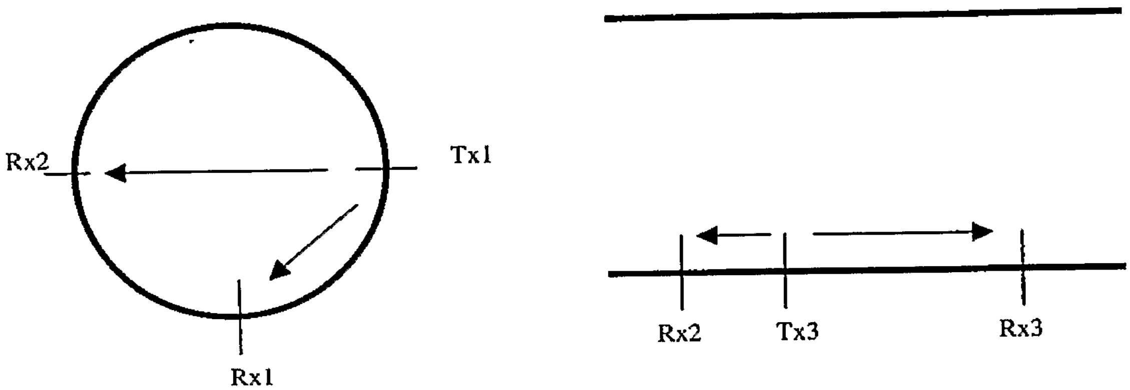


Fig.7

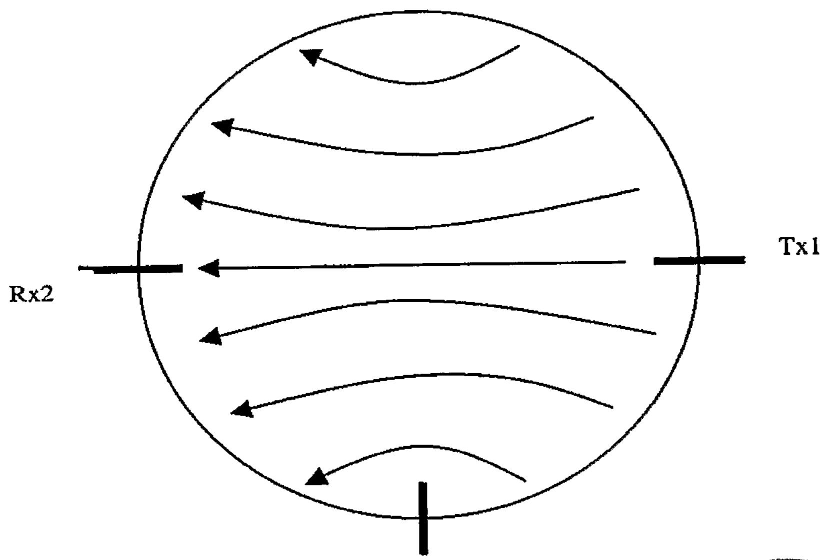


Fig. 8

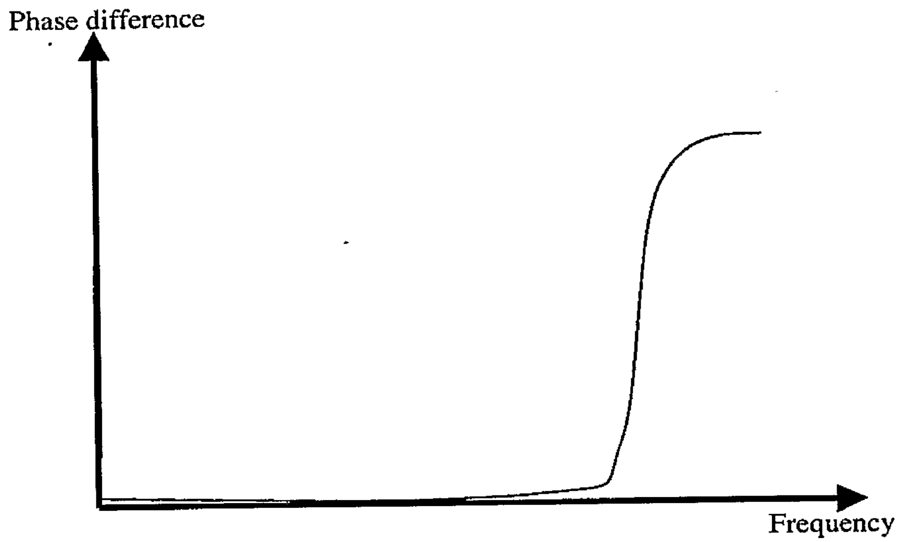


Fig. 9

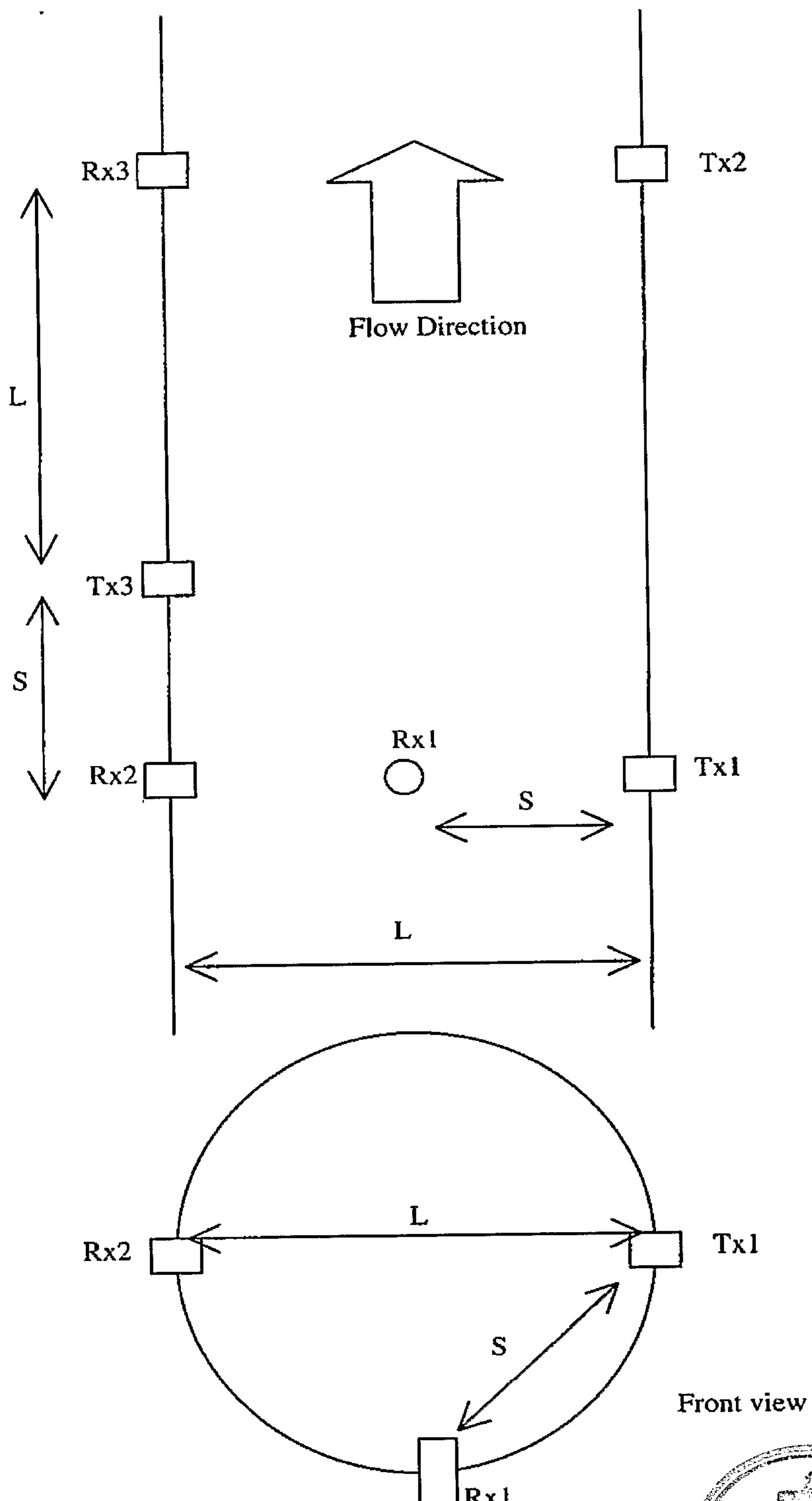

Rx3
Tx2
Flow Direction
L
Tx3
S
Rx1
Rx2
Tx1
S
L
L
Rx2
Tx1
S
Front view
Rx1

Fig. 10

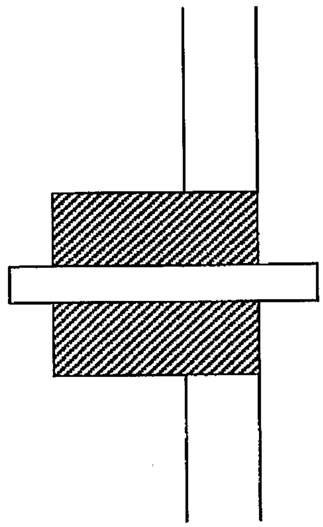


Fig. 11

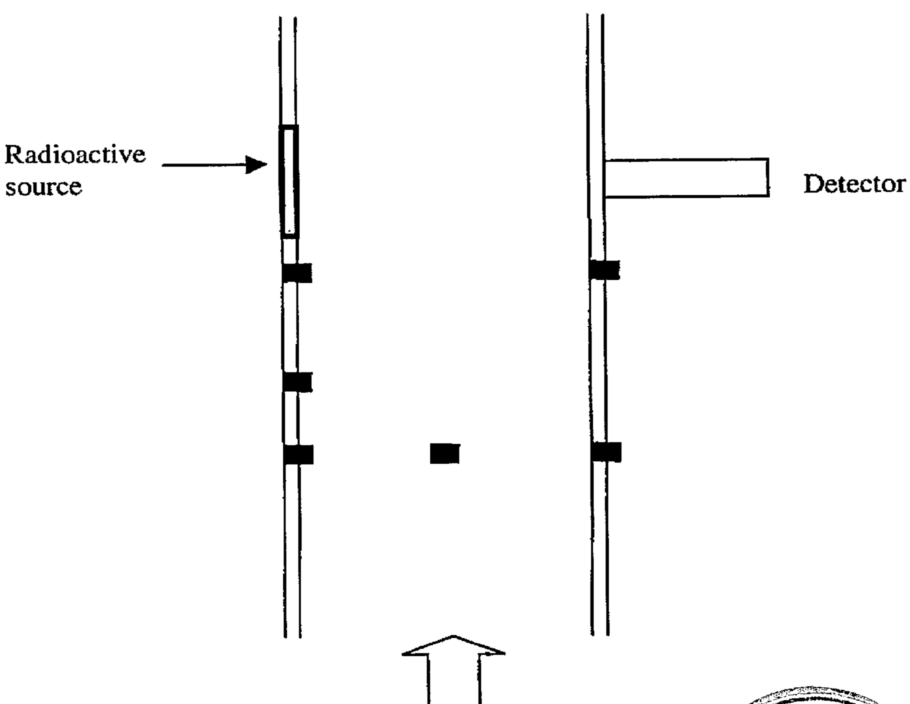


Fig. 12

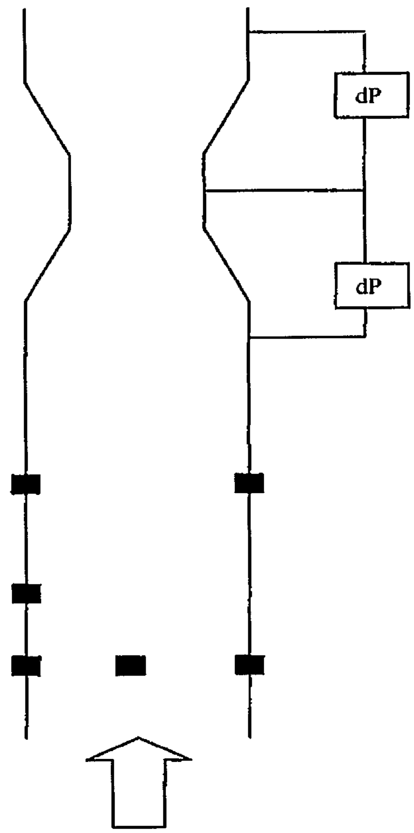
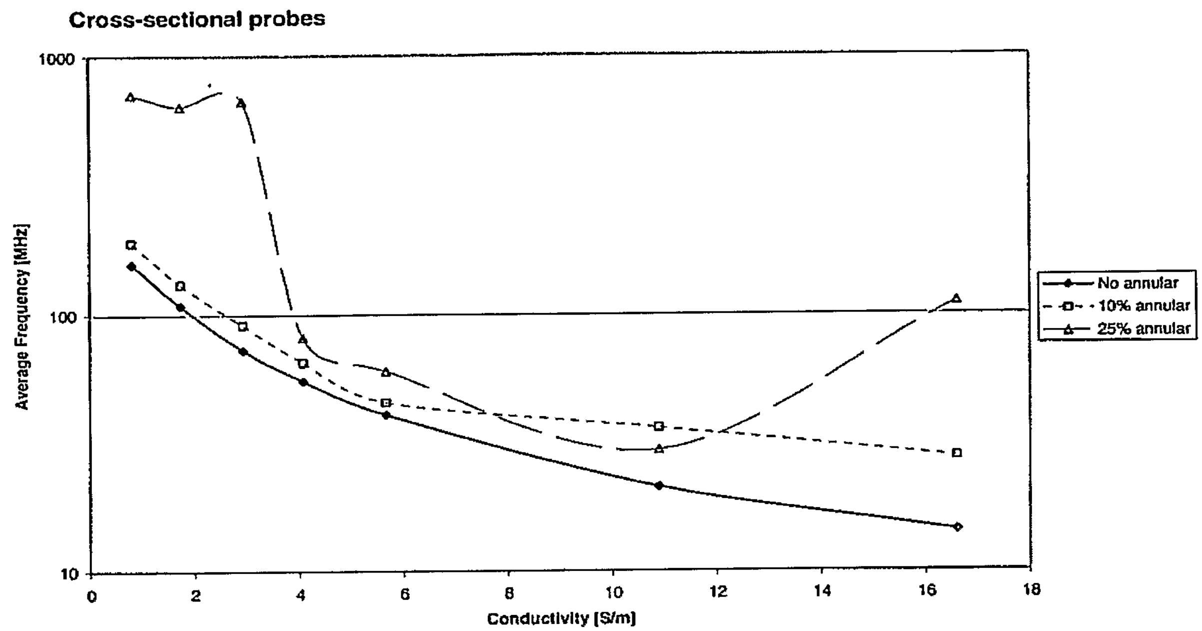
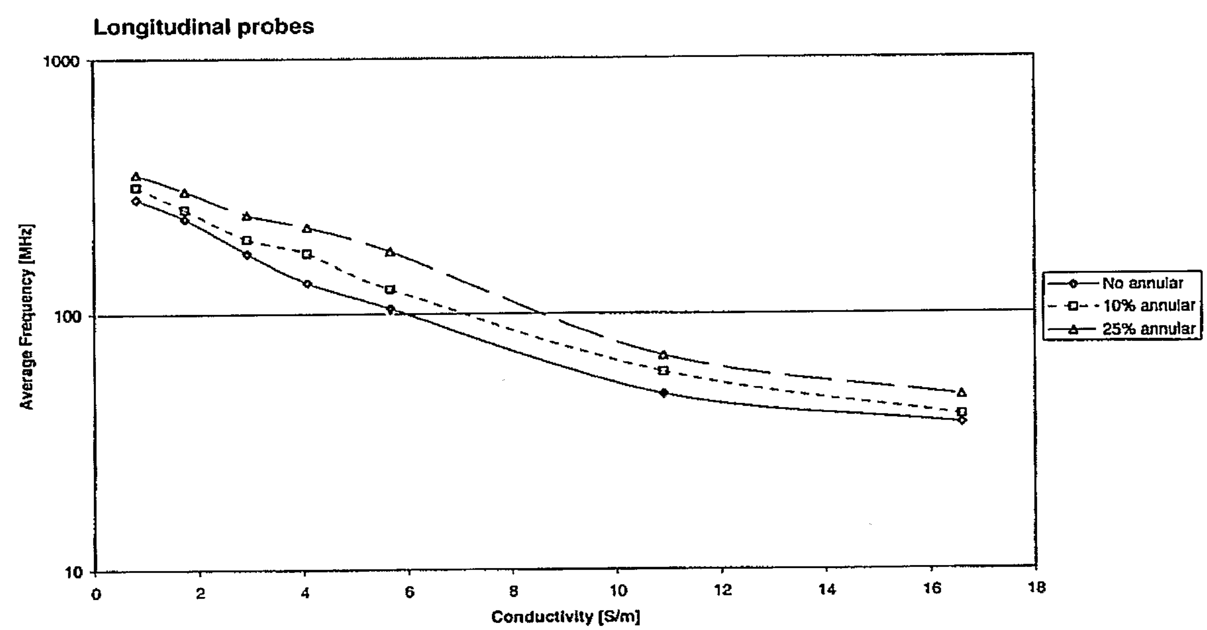


Fig 13



Cross-sectional probes
1000
100
10
Average Frequency [MHz]
0
2
4
6
8
10
12
14
16
18
Conductivity [S/m]
No annular
10% annular
25% annular

Fig. 14



Longitudinal probes
1000
100
10
Average Frequency [MHz]
0
2
4
6
8
10
12
14
16
18
Conductivity [S/m]
No annular
10% annular
25% annular

Fig. 15

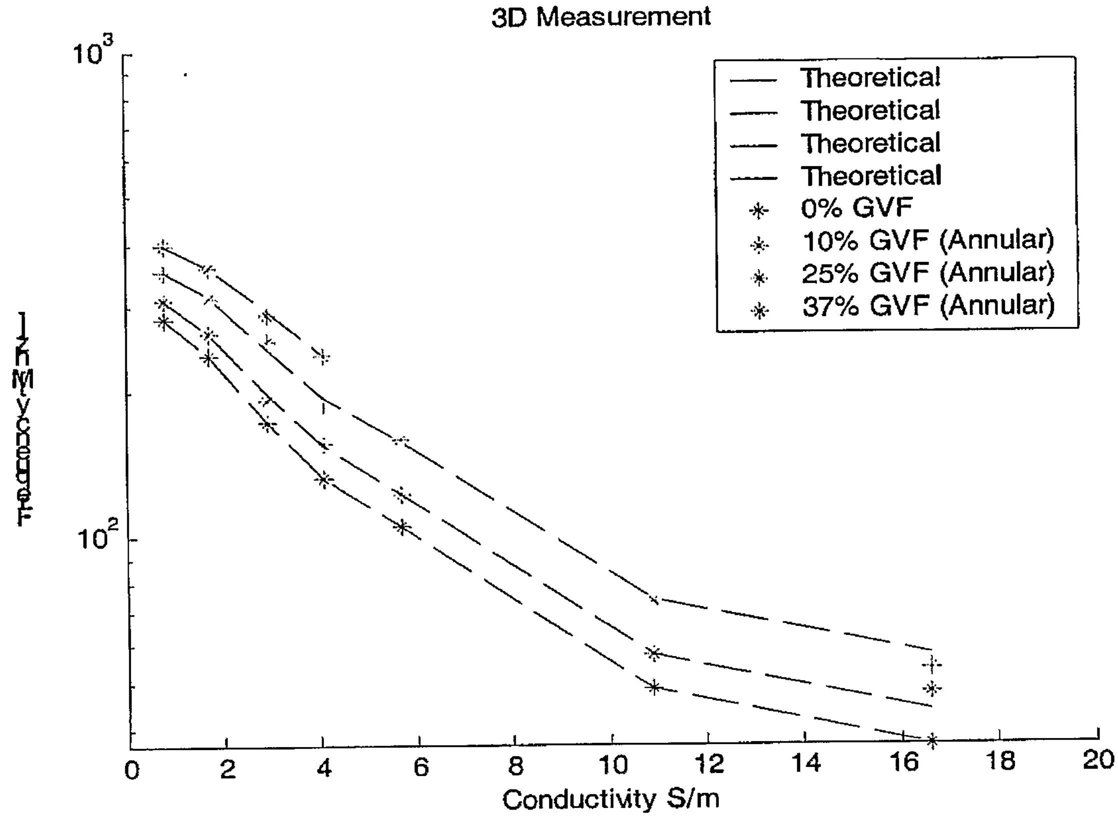

3D Measurement
Theoretical
Theoretical
Theoretical
Theoretical
0% GVF
10% GVF (Annular)
25% GVF (Annular)
37% GVF (Annular)
10^3
10^2
0
2
4
6
8
10
12
14
16
18
20
Conductivity S/m

Fig. 16

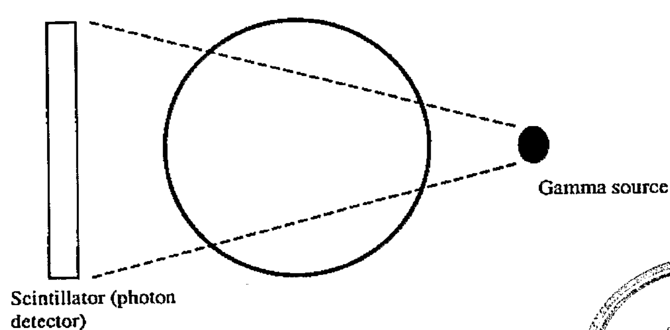

Gamma source
Scintillator (photon detector)

Fig. 17